DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA
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IN THE MATTER OF NorthWestern Energy's	)	
Application for Approval to Purchase and	)	REGULATORY DIVISION
Operate PPL Montana's Hydroelectric Facilities,	)	
for Approval of Inclusion of Generation Asset	)	DOCKET NO. D2013.12.85
Cost of Service in Electricity Supply Rates, for	)	
Approval of Issuance of Securities to Complete	)	
the Purchase, and for Related Relief	)	

HUMAN RESOURCE COUNCIL, DISTRICT XI; AND THE
NATURAL RESOURCES DEFENSE COUNCIL
RESPONSE TO
DATA REQUESTS PSC-355 THROUGH PSC-363
OF THE MONTANA PUBLIC SERVICE COMMISSION

PSC-355
Regarding: Determined Variables
Witness: Power

On 5:20-22 you state: "The word 'deterministic' refers to the fact that this approach assumes that future values of various variables are known with certainty, i.e. there is no uncertainty about them."

Do you agree that deterministic modeling does not assume that future values are known with certainty but rather conditions model output upon a determined set of values for predictor variables rather than values drawn from probability distributions? Certainly the analyst will understand that a determined set of variables is drawn from a much larger set of all reasonable values for the predictors.

Response

"Deterministic" modeling takes a given set of assumed data values and a given set of model coefficients (along with a given structure of the mathematical relationships between data values, coefficients, and outcomes) and calculates the value of other variables of interest. The assumed known data, coefficients, and mathematical relationships dictate a value for the variable of interest. All are “certain” in the sense that everything is pre-specified and the “solution” is unique.

How the analyst interprets or presents the results is not something that can be predicted with “certainty.”

PSC-356
Regarding: NorthWestern’s DCF Model
Witness: Power

On 22:24-29 you state: “Dr. Wilson, however, primarily relies on NWE’s DCF modeling. This reliance solely on the more primitive valuing technique is useful to Dr. Wilson because it allows him to continue to act as if future electric market prices and natural gas prices are known with certainty …”

Do you agree that Dr. Wilson had much greater access to the DCF model than to the stochastic PowerSimm model, and that this advantage in access may have been a greater source of comparative utility to Dr. Wilson regarding the DCF model?

Response

Dr. Power’s criticism was not that Dr. Wilson made use of the DCF model but of his interpretation of the results of the DCF model. It is the treatment of projected future electric market prices as a known reliable reference point against which all alternatives should be compared about which Dr. Power was concerned.

The DCF model is easier to use both because it is much simpler than PowerSimm and because, as this question points out, the PowerSimm stochastic model is a proprietary model that could only be “redone” or “modified” on request to the model’s owner and with the cooperation of NWE. That, however, does not prevent the analyst from recognizing the uncertainty surrounding the assumptions being fed into the DCF model and the uncertainty surrounding the apparent results of that modeling.

PSC-357
Regarding: Market Exposure Correlated to Hydroelectric Generation
Witness: Power

When asked whether there is “uncertainty about future electric market prices,” you begin your reply, “Certainly. There is a monthly pattern of movement of those market prices across the year because of the heavy hydroelectric production during spring and early summer when the snowpack is melting” (3:6-10). In what sense would owning and operating Hydros insulate their owner from the risk of market volatility owing to hydroelectric generation? Would it not be the case that the Hydros would not be producing when other hydroelectric generation was not producing, and would be producing when other hydro generators were producing, thus creating a market exposure problem that parallels other hydroelectric generation owners, as they seek to dump surplus onto a depressed market, or seek high-cost gas-fired electricity when the Northwest is dry?

Response

The quotation from Dr. Power's Response Testimony was taken from a section of his testimony in which he was listing all of the physical and market characteristics that make Pacific Northwest electric markets uncertain. Dr. Power did not assert that the purchase of the hydros would reduce the fluctuations in or protect NWE customers from the fluctuations in Pacific Northwest electric market prices tied to the annual cycle of melting snowpack, high water flow, and high levels of hydro generation followed by reduced late summer, fall, and winter flows and lower generation.

The Montana "hydros" whose purchase is at issue in this case are located on either side of the Continental Divide with Thompson Falls on the Columbia side and the rest of the hydros on the Missouri side. All of them are at the eastern edge of the "Pacific Northwest" climatic region. As a result, one can expect some diversity in the Montana hydro generation compared to the mainstem Columbia dams.

However, all of the hydros are at the headwaters of the river systems on which they are located and are influenced significantly by melting snowpack and the accompanying spring runoff. That is a well know pattern. When the hydroelectric facilities were built they were not built to sell into a regional market for a profit during the spring runoff. In fact, those facilities were not designed to run all of the spring runoff through the generators. Similarly, the low flows during the late summer were recognized when these facilities were designed and built. Their design focused on making the optimal economic use of the water available across the year. For that reason the addition of the hydros has to be evaluated in the context of NWE's overall portfolio, not as a stand-alone set of facilities.

Electric utilities dependent on hydroelectric facilities with a particular seasonal pattern have designed their overall generation portfolios to deal with that hydro variability and reduced their need to buy on the market when hydro supply is low and sell on the market when hydro supply is high.

It is true that relying on the market, as this question states, "creates market exposure problems" that utilities should plan to avoid. Dr. Power's testimony emphasized the importance of recognizing the costs associated with simply accepting that "market exposure" by relying on the market to meet a significant part of customers' demands.

PSC-358
Regarding: Market Risk
Witness: Power

a. Do you agree, generally, that there are risks to buying and owning assets in a market that has many downward excursions, just as there are risks to buying power in a market that has many upward excursions?

b. The Pacific Northwest has continued to add generating resources as the federal government has subsidized renewables with the production and investment tax credits, and as states have mandated the construction of renewable energy generators—even when demand is flagging or even decreasing—leading to more and more supply to serve a demand that is stagnant. How should the Commission factor this consideration into its evaluation of "market risk"?

c. You represent in the table on page 4 of your testimony the "Historic Daily Mid-C Power Price and Sumas Gas Price." Aren't most utilities relatively insulated from daily volatility, even if they do not own resources, because they sign medium- or long-term power purchase agreements that insulate them from sudden increases and depressions in price?

Response

a. No. Unless a business or individual is purposely engaged in market speculation, most businesses and individuals are risk adverse, meaning that the downside risks of loss matter more to them than upside potentials for gain.

If an electric utility has significant excess generating capacity and relies on sales into the regional electric market to recover the capital costs of that excess generating capacity to keep its retail customers' rates at reasonable levels, then the risk of low market prices *will be* of concern to risk adverse customers.

Merchant generators may seek to play both low and high market prices to their advantage, but that is not a strategy that regulated Montana utilities have wanted to engage in or been encouraged to engage in by the Montana Commission.

For a utility with limited generating facilities of its own, the risk associated with high and low market prices are not symmetrical. NWE has very little to sell into the market and a sizable necessity to buy in that market regardless of market conditions.

b. Dr. Power does not agree with the characterization of either public policy or market conditions assumed in this Data Request and therefore cannot factually respond to it.

It certainly is true that public policy at the state and federal levels as well as the business plans of many electric utilities have sought to encourage increased reliance on low-carbon, renewable energy sources. That policy does not appear likely to be abandoned any time soon. In fact, under the proposed EPA regulations aimed at reducing the carbon emissions from existing fossil fueled electric generators, the focus on renewable sources of electric generation and efficient reductions in demand are likely to intensify.

c. The volatility in electric market prices is not limited to daily fluctuations. There are fluctuations across months and years. It is true that many utilities take steps to reduce their exposure to such market price fluctuations by arranging for electric supply costs not to vary as much as short-term market prices do. Usually regulated utilities do this by owning a substantial part of the generating capacity needed to serve their customers loads. That is what NWE is proposing to do in this case. Alternatively utilities can contract for purchase of electricity at fixed prices for longer or shorter periods of time. NWE has done that with PPLM over the last decade. But even a five-year contract can create a "cliff" as the end date of the contract approaches. NWE is very familiar with that problem.

Of course, if it were possible, a utility could enter into a purchase power agreement with a fixed price or a mix of fixed and variable components that would mimic ownership of a generating facility. Whether there would be any advantages of such a "market" purchase that mimicked the purchase of an existing generator or the construction of a new generator would have to be carefully analyzed.

PSC-359
Regarding: Projections' Coherence to Typical Market Behavior
Witness: Power

Whether in PowerSimm's analysis or in Mr. Stimatz's DCF analysis, or in Dr. Wilson's reworking of that analysis, the electricity price forecast surges suddenly in 2021 (or, in the illustrative scenario provided by Dr. Wilson, which you restate on p. 6 of your testimony, in 2031). In your experience, is this usually how long-term market prices look—slowly inclining prices, followed by a sudden surge, followed by slowly inclining prices from the post-surge baseline? Assuming it is not, how could the Commission create a more accurate glidepath that incorporates carbon pricing, but does not assume the all-at-once surge in market prices that appears to be central to NorthWestern's assumptions?

Response

Commodity prices often do make sudden and substantial changes. For instance natural gas wellhead prices surged upwards in 1998 and with some severe fluctuations continued to move upward through the middle of 2009. Then natural gas prices plummeted and continued their decline through the beginning of 2012 when a slow recovery began. (EIA U.S. Natural Gas Prices) Oil prices have behaved similarly, rising dramatically beginning in 1999 and continuing to rise through 2011.

However, this is not the way that future commodity prices are usually projected. Since major disruptive events cannot be accurately predicted, projections usually show a relatively smooth “glide path” even though we know that that is unlikely to describe how the market price will actually behave. The reason for the smooth “glide paths” is that we do not know what the future holds not because we expect such smooth behavior in market prices.

It is not clear that modeling a smooth glide path interrupted by a sudden policy-driven change in price and then a return to a smooth glide path distorts long-run economic evaluation. Given that 30 years of performance are being projected, the exact shape of the projected price curve in any given time period may not matter as much as the overall long-run trend.

PSC-360
Regarding: Cost of Insurance
Witness: Power

You argue that utilities engage in an “insurance” strategy (9:29) to mitigate the risk of market purchases which, while they are projected to cost less over a period of time than a particular asset (like the Hydros), could end up costing more. Is there an equation or method that the Commission should bring to bear in calculating an acceptable value to that insurance policy? How would the Commission determine the point at which the insurance became too expensive for the risk it was attempting to mitigate?

Response

An objective formula for evaluating the “rational” level of insurance is not possible because risk preferences are subjective, varying among individuals and businesses. The risk preference adopted by government agencies in the name of citizens or utility customers is necessarily a public policy decision for government decision-makers.

In situations where risk preferences are known, the negative events against which insurance might be purchased are well understood, and there is data readily available on the loss probabilities, economic theory can theoretically specify rational insurance purchasing behavior. Whether that theory is consistent with actual economic behavior is debated among economists. Where the loss probabilities are not known and the distribution of the losses among those impacted may also be unknown and the specification of risk preferences is difficult, no rule can be specified.

PSC-361
Regarding: Terminology of Market Reliance
Witness: Power

a. When you discuss reliance on the market, what specific length of time do you imagine when you use the phrase “short-term purchases” (17:28)?

b. Why should a long-term PPA for a particular unit (such as Judith Gap) be considered a market source of supply?

c. Why should a long- or medium-term PPA for networked resources (such as the PPLM plants) be considered a "short-term purchase?"

d. Is there a risk that a false dichotomy is being drawn in this docket between a notion that utility-owned resources are the only rate-stable, secure resources versus everything else being lumped in under the aegis of volatile "markets"? Please explain.

Response

a. Typically "short-term" refers to contracts of a year or less.

b. Any commercial contract between a willing buyer and willing seller (who are informed and not coerced) can be considered a "market transaction." In that sense a utility decision to enter into a long-run PPA or to purchase a generator or to construct a new generator could all be considered market decisions.

c. By definition, a "long-term or medium-term PPA" is not a "short-term purchase." That does not mean that there are not varying degrees of market risk associated with contracts with different time durations and/or different exposures to variable costs.

d. That *is* one false dichotomy that might develop. Another could be that the market is a reliable, well-understood, low cost source of electric supply that allows the utility to avoid the burden of fixed costs versus utility-owned supply or long-term power purchase agreements that include these fixed costs.

One can enter into market transactions to supply NWE's customers in a variety of ways each of which is likely to have a different market (and possibly other) risks and different costs. Relying entirely on very short-term spot market prices might be one choice. Buying an electric generator, entering into a long-term fixed price contract for fuel, and buying an insurance policy against any generator failure could be another. They are all market transactions. That does not tell us much. What is at issue is what the size of the market risks as well as other risks are.

PSC-362

Regarding: Alleged Stochasticity of Carbon Price Analysis
Witness: Power

At 19:14-19 you state: "[Stochastic analysis] does try to build the uncertainty about the values of the most important variables and an understanding of their frequency distribution directly into the evaluation of alternative electric supply portfolios. In that sense, more information is introduced into the modeling, allowing it to more accurately represent the resource supply decisions in the context of uncertainty."

a. Would you agree that forecast carbon prices is one of the most important variables in this resource analysis?

b. With respect to carbon prices, doesn't NWE's "stochastic" analysis simply reify a deterministically selected value which is placed in the middle of a triangular distribution, with equal distributions on either side of the deterministically selected value? In what sense is more useful information regarding past behavior of carbon prices introduced into the model using this probability distribution?

Response

a. Yes.

b. Simple pre-specified frequency distributions (triangular, rectangular, etc.) are used when there is "no useful information regarding past behavior" available. If we had such information, it would be used instead to inform the choice of expected future frequency distribution.

When such data is not available from the past, but when the decision-maker has limited information about reasonably expected most likely, maximum, and minimum values, a triangular distribution can be used to describe a future frequency distribution. Using the triangular distribution conveys more information than just using the single "most likely" value. The expected maximum and minimum values are also built into the frequency distribution.

PSC-363
Regarding: NRDC Carbon Study
Witness: Power

a. Are you familiar with a study your client, NRDC, has conducted entitled "Cleaner and Cheaper: Using the Clean Air Act to Sharply Reduce Carbon Pollution from Existing Power Plants," the conclusions of which have been presented around the country, including at a recent Northwest Energy Coalition event in Helena, Mont., on May 2? (Available online at: http://www.nrdc.org/air/pollution-standards/)

b. Have you had an opportunity to review the carbon prices for the Pacific Northwest that NRDC claims would be necessary to achieve various carbon-reduction scenarios (e.g., Moderate Case Full EE, Moderate Case Constrained EE, Ambitious Case Full EE, Ambitious Case Constrained EE, Ambitious Case Constrained EE PTC"?

c. For each of those scenarios, how do the carbon prices your client projects would be necessary to achieve these large carbon reduces *[sic]* compare to the carbon price that NWE is forecasting in this proceeding?

RESPONSE

a. Yes.

b. The cited NRDC document was a March 2014 update of a more detailed analysis released in March 2013 (“Cleaner and Cheaper,” R:12-11-A). The cited document did not report any regional results (e.g. Pacific Northwest). It focused exclusively on the nation as a whole. The earlier 2013 NRDC study did report some modeling results by electric control regions (ISOs) but the Pacific Northwest and most of the rest of the West were not explicitly modeled in that analysis. So there are no Pacific Northwest results from these NRDC studies.

c. These studies did not calculate “carbon prices” that “would be necessary to achieve these large carbon” reductions. Instead, the analysis looked at the annualized costs associated with the adjustments that utilities would make to meet the carbon emissions reductions that were assumed to be mandated by 2020. A cost-minimizing integrated resource planning model was used to project how utilities would respond to reduce their carbon emissions and what the annualized cost of compliance would be.

For the nation as a whole, the NRDC estimate average cost per metric ton of carbon emission avoided in 2020 was between $14.20 and $24.02 in 2012 dollars. NWE assumed a carbon cost of $15 per metric ton in 2014 that did not take effect until 2021 at which time the cost would have increased by 5 percent per year to $21.11. If the NRDC carbon costs per metric ton are expressed in 2020 $s, they would be much higher than NWE’s assumed carbon cost in 2021, ranging from $24.33 to $41.17 per metric tonne. See the table below

NRDC Senarios Modeled	Emission Reduction millions of short tons of CO2 (per year)	Incremental Annualized Cost Billions of 2012$	Annualized Unit Cost to Reduce Carbon Dioxide Emissions by Specified Amount		
			Cost per Short Ton of Carbon Emissions Avoided 2012$s	Cost per Metric Tonne of Carbon Emissions Avoided 2012$s	Cost per Metric Tonne in 2020 Assuming 5%/yr. Inflation Rate
Reference	0	0			
Moderate, Full Efficiency	530	0	$0.00		
Moderate, Constrained Efficiency	470	6.6	$14.04	$15.48	$26.53
Ambitious, Full Efficiency	660	8.5	$12.88	$14.20	$24.33
Ambitious, Constrained Efficiency	670	14.6	$21.79	$24.02	$41.17
Ambitious, Constrained Eff & PTC	700	11.1	$15.86	$17.48	$29.96

Source: Columns 2 and 3 from "Cleaner and Cheaper," NRDC Issue Brief Update, March 2014, IB:14-03-A, Table 1, p.7
Columns 4, 5, and 6, Power Consulting Inc., calculations.

It should be noted that the NRDC average cost of attaining the targeted carbon reductions are underestimates of the marginal cost of reaching the last unit of carbon emission reduction sought. In that sense, the implicit NRDC marginal cost of carbon reduction in 2020 is even higher than the table above suggests.